Western Massachusetts Electric

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Stephen Klionsky, Esq.

September 27, 2005

Ms. Mary L. Cottrell
Secretary
Dept. of Telecommunications & Energy
One South Station
Boston, MA 02110

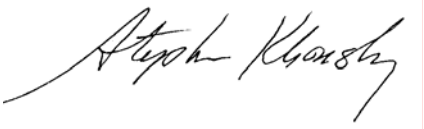
Re: Docket No. DTE 05-10 - 2004 TC Reconciliation Filing

Dear Ms. Cottrell:

This letter provides the response to requests for the information listed below.

Response to HD-01 Interrogatories dated 09/13/2005
RR - 001 , 002 , 003 , 004

Very truly yours,



Stephen Klionsky

SK/jms

Witness: **Michael J. Mahoney**
Request from: **Department of Telecommunications and Energy**

Question:
Describe how the Transition Charge has been arrived at for each rate class, and describe the steps taken, if any, to ensure there are no inter-class subsidies in the collection of Transition Costs.

Response:
The Company has designed its Transition Charges (Customer, Demand, Energy) to collect Transition Revenues for each rate class at the same average cents per kilowatt-hour. Since each rate class is designed to collect the same average Transition rate per kilowatt-hour there are no inter-class subsidies in the collection of Transition revenues. The Company has not performed any specific analysis on actual revenues to determine if inter-class subsidies exist. Please refer to the Company's response HD-01, Q-RR-002 for further explanation of this issue.

Witness: **Michael J. Mahoney; Robert A. Baumann**
Request from: **Department of Telecommunications and Energy**

Question:
Please explain why the transition charge per kWh as calculated on Exhibit AG-2 is different than the calculation shown on Exhibit MJM-2 for years 2003 and 2004. Also, explain why Exhibit AG-2 (Excel spreadsheet) is not useable.

Response:
Exhibit MJM-2 shows the average Transition rate (1.424 c/kWh 2003, 0.828 c/kWh 2004) that the Company has designed its rates to collect. Exhibit AG-2 shows an average residential Transition rate of 1.53 c/kWh for 2003, and 0.916 c/kWh for 2004. The sales used in the AG-2 calculation are sales to customers in Rates R-1, R-2, R-3, and R-4 and are not total residential sales. Total residential sales also include customers which are billed on Rates 23, G-0, G-2, T-0, T-2, and S-1. Use of these sales in Exhibit AG-2, would have produced values very close to those shown in MJM-2. However, any comparison between designed rates and actual rates will always yield small differences as actual rates contain (1) different sales mix and demand levels versus the designed rate period, (2) designed rates use calendar sales versus actual recorded billed sales, and (3) actual sales contain billing adjustments (cancel, rebills) not assumed in design rates.

Please see response to Record Request Q-RR-003 for transition charge revenues, sales, and average transition c/kWh by customer class by rate for the 2003 and 2004 period.

Witness: **Michael J. Mahoney; Robert A. Baumann**
Request from: **Department of Telecommunications and Energy**

Question:
Please provide the actual transition revenue on a cents/kWh basis for each rate class for years 2002, 2003, and provide a similar explanation for year 2004. (The calculation should be performed as: Revenues for each rate ((R1,R2,R3, etc.,) divided by annual kWh sales for each rate))

Response:
Please see attached pages 2 through 7 for Transition revenues, sales, and average Transition c/kWh, by customer class by rate for years 2002, 2003, and 2004. Customers who are metered on the higher voltage side of the service transformer receive a 2 percent Primary Metering Credit to their billed sales. The Company for this response has provided Billing Month Sales (see column B) by class by rate and Billing Month Sales less Primary Metering Sales (see column E) at the customer class level only as they are not readily available at the rate level.

Western Massachusetts Electric Company

2002 Transition Revenues

	Rate	Transition Revenues ($000s) (A)	Billing Month Sales (MWh) (B)	Cents per kWh C= A/B *100	Primary Metering Credits (PMC) (MWh) (D)	Billing Month Sales less PMC (MWh) E = B - D	Cents per kWh F= A/E *100
Residential	R-1	13,017	982,918	1.324			
	R-2	1,337	102,540	1.304			
	R-3	3,111	237,259	1.311			
	R-4	362	27,148	1.335			
	23	3	201	1.304			
	G-0	396	31,118	1.273			
	T-0	0.3	21	1.338			
	G-2	759	60,224	1.260			
	S-1/S-2	23	1,797	1.307			
	T-2	228	18,732	1.217			
	Total	**19,237**	**1,461,957**	**1.316**	**470**	**1,461,488**	**1.316**
Commercial							
	23	2	118	1.293			
	24	99	7,565	1.308			
	G-0	6,081	462,932	1.314			
	T-0	27	2,146	1.272			
	G-2	4,534	347,001	1.307			
	T-4	120	9,179	1.304			
	S-1/S-2	149	11,348	1.309			
	T-2	7,860	579,145	1.357			
	Contracts	1,488	112,076	1.328			
	Total	**20,359**	**1,531,508**	**1.329**	**6,446**	**1,525,063**	**1.335**
Industrial							
	23	0.5	36	1.345			
	G-0	308	23,102	1.334			
	T-0	1	76	1.580			
	G-2	1,303	95,369	1.367			
	T-4	31	2,517	1.238			
	S-1/S-2	12	1,009	1.231			
	T-2	8,104	636,980	1.272			
	I-3	30	2,293	1.309			
	PR	899	67,123	1.339			
	Contracts	1,046	90,356	1.157			
	Total	**11,736**	**918,863**	**1.277**	**10,520**	**908,343**	**1.292**

Western Massachusetts Electric Company

2002 Transition Revenues

	Rate	Transition Revenues ($000s) (A)	Billing Month Sales (MWh) (B)	Cents per kWh C= A/B *100	Primary Metering Credits (PMC) (MWh) (D)	Billing Month Sales less PMC (MWh) E = B - D	Cents per kWh F= A/E *100
Street Lighting	G-0	55	4,504	1.218			
	G-2	3	268	1.248			
	S-1/S-2	310	22,997	1.349			
	Total	**368**	**27,769**	**1.327**	**0**	**27,769**	**1.327**
Total	R-1	13,017	982,918	1.324			
	R-2	1,337	102,540	1.304			
	R-3	3,111	237,259	1.311			
	R-4	362	27,148	1.335			
	23	5	355	1.304			
	24	99	7,565	1.308			
	G-0	6,841	521,656	1.311			
	T-0	29	2,243	1.283			
	G-2	6,599	502,861	1.312			
	T-4	151	11,696	1.290			
	S-1/S-2	495	37,151	1.331			
	T-2	16,192	1,234,856	1.311			
	I-3	30	2,293	1.309			
	PR	899	67,123	1.339			
	Contracts	2,534	202,432	1.252			
	Total	**51,700**	**3,940,097**	**1.312**	**17,436**	**3,922,662**	**1.318**

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2003 Transition Revenues

	Rate	Transition Revenues ($000s) (A)	Billing Month Sales (MWh) (B)	Cents per kWh C= A/B *100	Primary Metering Credits (PMC) (MWh) (D)	Billing Month Sales less PMC (MWh) E = B - D	Cents per kWh F= A/E *100
Residential	R-1	14,335	1,008,327	1.422			
	R-2	1,548	111,766	1.385			
	R-3	3,589	253,018	1.418			
	R-4	441	31,207	1.414			
	23	3	186	1.421			
	G-0	440	31,884	1.381			
	T-0	0.3	20	1.443			
	G-2	846	61,722	1.370			
	S-1/S-2	26	1,802	1.417			
	T-2	254	19,071	1.334			
	Total	**21,482**	**1,519,004**	**1.414**	**486**	**1,518,518**	**1.415**
Commercial							
	23	1	98	1.384			
	24	110	7,728	1.419			
	G-0	6,712	476,598	1.408			
	T-0	31	2,266	1.384			
	G-2	4,807	342,082	1.405			
	T-4	123	8,858	1.387			
	S-1/S-2	162	11,444	1.418			
	T-2	8,848	599,678	1.475			
	Contracts	1,579	113,040	1.397			
	Total	**22,374**	**1,561,792**	**1.433**	**8,526**	**1,553,266**	**1.440**
Industrial	23	0.1	6	1.418			
	G-0	362	25,135	1.440			
	T-0	2	96	1.621			
	G-2	1,329	91,136	1.458			
	T-4	37	2,728	1.370			
	S-1/S-2	14	989	1.419			
	T-2	8,785	654,263	1.343			
	I-3	25	1,773	1.420			
	PR	838	62,879	1.333			
	Contracts	823	68,325	1.204			
	Total	**12,214**	**907,331**	**1.346**	**10,687**	**896,644**	**1.362**

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2003 Transition Revenues

	Rate	Transition Revenues ($000s) (A)	Billing Month Sales (MWh) (B)	Cents per kWh C= A/B *100	Primary Metering Credits (PMC) (MWh) (D)	Billing Month Sales less PMC (MWh) E = B - D	Cents per kWh F= A/E *100
Street Lighting	G-0	53	4,043	1.307			
	G-2	4	268	1.367			
	S-1/S-2	310	21,788	1.422			
	Total	**366**	**26,099**	**1.403**	**0**	**26,099**	**1.403**
Total							
	R-1	14,335	1,008,327	1.422			
	R-2	1,548	111,766	1.385			
	R-3	3,589	253,018	1.418			
	R-4	441	31,207	1.414			
	23	4	291	1.408			
	24	110	7,728	1.419			
	G-0	7,567	537,660	1.407			
	T-0	33	2,383	1.394			
	G-2	6,985	495,208	1.411			
	T-4	160	11,586	1.383			
	S-1/S-2	512	36,023	1.420			
	T-2	17,887	1,273,013	1.405			
	I-3	25	1,773	1.420			
	PR	838	62,879	1.333			
	Contracts	2,402	181,364	1.324			
	Total	**56,436**	**4,014,227**	**1.406**	**19,699**	**3,994,527**	**1.413**

Western Massachusetts Electric Company

2004 Transition Revenues

	Rate	Transition Revenues ($000s) (A)	Billing Month Sales (MWh) (B)	Cents per kWh C= A/B *100	Primary Metering Credits (PMC) (MWh) (D)	Billing Month Sales less PMC (MWh) E = B - D	Cents per kWh F= A/E *100
Residential	R-1	8,610	1,010,278	0.852			
	R-2	965	119,562	0.807			
	R-3	2,112	245,200	0.862			
	R-4	255	29,874	0.855			
	23	1	155	0.843			
	G-0	270	33,187	0.813			
	T-0	0.2	19	0.915			
	G-2	514	63,080	0.815			
	S-1/S-2	16	1,829	0.857			
	T-2	128	15,891	0.805			
	Total	**12,871**	**1,519,075**	**0.847**	**438**	**1,518,637**	**0.848**
Commercial	23	1	86	0.858			
	24	65	7,591	0.856			
	G-0	4,157	492,006	0.845			
	T-0	17	2,003	0.849			
	G-2	2,813	336,060	0.837			
	T-4	69	8,462	0.820			
	S-1/S-2	99	11,434	0.862			
	T-2	4,986	595,372	0.838			
	Contracts	920	113,056	0.814			
	Total	**13,128**	**1,566,070**	**0.838**	**8,912**	**1,557,158**	**0.843**
Industrial							
	G-0	227	25,951	0.876			
	T-0	1	126	1.061			
	G-2	792	89,167	0.888			
	T-4	20	2,450	0.836			
	S-1/S-2	8	973	0.854			
	T-2	5,505	680,767	0.809			
	I-3	3	319	0.924			
	PR	669	76,399	0.876			
	Contracts	328	51,735	0.633			
	Total	**7,554**	**927,887**	**0.814**	**10,687**	**917,200**	**0.824**

Western Massachusetts Electric Company

2004 Transition Revenues

	Rate	Transition Revenues ($000s) (A)	Billing Month Sales (MWh) (B)	Cents per kWh C= A/B *100	Primary Metering Credits (PMC) (MWh) (D)	Billing Month Sales less PMC (MWh) E = B - D	Cents per kWh F= A/E *100
Street Lighting	G-0	26	3,467	0.747			
	G-2	2	270	0.807			
	S-1/S-2	177	21,246	0.835			
	Total	**205**	**24,983**	**0.822**	**0**	**24,983**	**0.822**
Total	R-1	8,610	1,010,278	0.852			
	R-2	965	119,562	0.807			
	R-3	2,112	245,200	0.862			
	R-4	255	29,874	0.855			
	23	2	240	0.848			
	24	65	7,591	0.856			
	G-0	4,680	554,610	0.844			
	T-0	19	2,149	0.862			
	G-2	4,121	488,577	0.844			
	T-4	90	10,912	0.824			
	S-1/S-2	300	35,482	0.845			
	T-2	10,619	1,292,029	0.822			
	I-3	3	319	0.924			
	PR	669	76,399	0.876			
	Contracts	1,248	164,791	0.757			
	Total	**33,759**	**4,038,015**	**0.836**	**20,286**	**4,017,729**	**0.840**

Witness: **Michael J. Mahoney**
Request from: **Department of Telecommunications and Energy**

Question:
a) Please provide the FERC tariffs that provide for recovery of Scheduling and Dispatch expenses and b) explain in detail why the inclusion of Account 561 in this tariff is not double collecting.

Response:

a). WMECO recovers its Scheduling and Dispatch (S&D) costs associated with regional pooled transmission facilities (PTF) and local non-pooled transmission facilities (non-PTF) through two separate and distinct charges. WMECO pays for S&D service through three separate charges; regional PTF, local non-PTF and ISO administrative charges associated with S&D.

Regional PTF charges
On an annual basis the Company provides ISO New England with an annual level of PTF costs which is derived by taking account 561 and multiplying it by a PTF plant allocation factor. The regional S&D costs for all the Pooled Transmission Owners (PTO's) are then combined and a regional tariff is determined by dividing these costs by the combined loads of all of the PTO's. The tariff is charged to network customers (WMECO included) based on the tariff rate times Monthly Network Load. Revenues from the regional tariff are reallocated back to the Transmission Owners (WMECO included) by ISO based on their share of the filed revenue requirements to the total revenue requirements.

Currently FERC Tariff 3 , Section II Schedule 1, sheet 705 shows the derivation of the regional S&D charges to be submitted to the ISO annually (See page 4). Prior to 2/1/05 the charges to be submitted to ISO NE annually were based on the NEPOOL Tariff, Sheet 502 (see page 8). Both tariffs use account 561 times a PTF plant allocation factor.

Local non-PTF charges
On an annual basis, the Company determines its local non-PTF S&D costs by taking total account 561 and reducing it by the revenues received from the ISO associated with PTF as described above. WMECO's local costs are combined with the local costs of the other NU operating companies to determine total non-PTF S&D formula requirements. The formula requirements are charged to the NU operating companies (WMECO included) based on their load share. Revenues are reallocated back to the NU operating companies (WMECO included) based on their share of revenue requirements to the total revenue requirements.

Currently FERC Tariff 3, Section II, Schedule 21-NU, Attachment NU-1 sheets 3231 and 3232 show the derivation of the local S&D costs to be submitted for recovery (See pages 9 and 10). Prior to 2/1/05, but subsequent to 10/26/03 the FERC Tariff 10, Schedule 1, sheets 114 and 116 show the derivation of the costs to be submitted for recovery. (See pages 12 and 13). Both of these tariffs use total Scheduling and Dispatch costs less revenues associated with regional S&D costs. Prior to 10/27/03 the FERC Tariff 9,

Fourth Revised sheet No. 302 was the basis for recovery of S&D expense. Recovery level was settlement based (See pages 14 and 15).

ISO administrative charges associated with S&D

WMECO is also charged for their share of costs the ISO incurs in order to carry out its functions related to S&D under FERC tariff No. 3, Section IV.A, Schedule 1, sheets 8544 to 8547 (See pages 16 to 17).

See page 3 for a simplified example of how WMECO is impacted by the above revenues and expenses

b). As shown in part a). above, account 561 is not double collected through the S&D tariff components because revenues associated with the regional PTF S&D is deducted from total S&D costs to derive the local non-PTF S&D tariff.

In addition, there is not a double collection issue between the transmission service tariffs and the S&D tariffs because account 561 is not included in the O&M costs used to derive the transmission service component of the regional or local tariffs. See pages 18 to 21 for the pages from the regional and local transmission service tariffs which exclude account 561 from the O&M.

Scheduling and Dispatch (S&D) Overview
Simplified Example

-Assumes 60% PTF and 40% non PTF
-Assumes no regulatory lag in development of FERC tariffs
-Assumes WMECO stand alone costs of $100

	Account	A/C 561 Recovery		Other Charges		Total WMECO
WMECO S&D incurred costs	561.00	100	(a)			100
Regional S&D revenues	456.SD,SE,SF	(60)	(b)			(60)
Regional S&D expense	565.SD,SE,SF			53	(c)	53
Local S&D revenues	456.49	(40)	(d)			(40)
Local S&D expense	565.L3,N3			38	(e)	38
ISO S&D related administrative expense	557.S1			5	(f)	5
Total		0		96		96

(a) Stand alone costs incurred by WMECO related to S&D.
(b) Reimbursement of 60% of charges related to PTF (Regional Network) from ISO calculated as total account 561 times PTF plant allocation factor%. (Recovery based on FERC tariff No. 3, Section II, Schedule 1 Sheet 705) (See Page 4)
(c) WMECO share of all ISO-NE transmission providers regional S&D costs (Billed under FERC Tariff No. 3, Section II, Schedule 1- Sheets 706 to 708) (See pages 5 to 7)
(d) Reimbursement of charges related to non-PTF (Local Network) calculated as total account 561 less account 456 revenues which include revenues received from ISO related to PTF. ($100-$60). (Recovered based on FERC Tariff No. 3, Section II, Schedule 21 Revenue requirements- Sheets 3231 and 3232) (See Page 9 and 10)
(e) WMECO load share of NU's local network S&D costs. (Billed under FERC Tariff No. 3, Section II, Schedule 21- Sheet 3227). (See page 11)
(f) WMECO's share of ISO administrative costs to carry out functions associated with S&D. (Billed under FERC Tariff No. 3, Section IV.A, Schedule 1- Sheet 8544 to 8545) (See Pages 16 and 17)

Regional S+D revenues

PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the PTO from REMVEC II, CONVEX/ESCC, and the Maine Local Control Center as recorded in each PTO's FERC Form 1, Account No. 561, excluding any charges recorded in this account that were incurred under the OATT or Schedule 21 of the OATT. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the PTO for providing scheduling and dispatch services, excluding any revenues recorded in this account that where received as a result of charges under the OATT.

REMVEC II is a Local Control Center of the ISO providing security analysis of PTF.

Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each PTO's expenses as recorded in FERC Account No. 561, excluding any ISO and Local Control Center related expenses and any expenses recorded in this Account, that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer, multiplied by the PTF Transmission Plant Allocator, (2) Boston Edison Company SCADA-related expenses as calculated in accordance with Appendix A of this Rule, and (3) the Central Maine Power Company Local Control Center revenue requirements as calculated in accordance with Appendix B of this Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and Non-PTF as determined for the applicable period pursuant to Attachment F of the OATT.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers - wmeco is network customer

For Network Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Network Customer's Regional Monthly Network Load, as defined in Section II.21.2 of the OATT, multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

B. Surcharge for Through or Out Customers

For Through or Out Service Customers, the Scheduling and Dispatch Surcharge shall equal the Transmission Customer's Reserved Capacity for each transaction scheduled for the month multiplied by the applicable Monthly or Hourly Scheduling and Dispatch Surcharge Rate, as determined in accordance with Section II.C below.

C. Scheduling and Dispatch Surcharge Rate

The Scheduling and Dispatch Surcharge Rate will be the surcharge rate in effect from time to time for the applicable period, determined pursuant to the formula described below based on the prior calendar year's data. The Scheduling and Dispatch Surcharge Rate shall be redetermined each year, with the new Surcharge Rate going into effect on June 1 of each year, and be effective for the succeeding twelve months.

In the case of PTOs which are subject to the Commission's jurisdiction, the data used shall be as identified in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1. When FERC Form 1 data is not the direct source of the data used in the formula, the worksheets used to develop the inputs will reflect Appendix A and Appendix B of this Rule.

The Scheduling and Dispatch Surcharge Rate shall be equal to the sum of (1) PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense, (2) Local PTF Transmission Related Scheduling and Dispatch Expense, (3) less Schedule 1 revenues from the prior year surcharges for Short-Term Point-To-

Point Transactions, and divided by the annual average of the sum of all Regional Network Customers Monthly Peak Load, as defined in Section II.21.2 of the OATT, from the prior calendar year plus the Long-Term Firm Point-To-Point Service Reserved Capacity, from the prior calendar year.

The Monthly Scheduling and Dispatch Surcharge Rate shall equal one-twelfth of the Scheduling and Dispatch Surcharge Rate.

The Hourly Scheduling and Dispatch Surcharge Rate shall be the annual rate divided by 8760.

Capitalized terms used in this rule that are not defined in the NEPOOL Tariff have the following definitions:

Scheduling and Dispatch Surcharge Rate shall equal the rate surcharge that is determined for the applicable period beginning on June 1, 1999, in accordance with Section II of this rule below.

PTF Transmission-Related Satellite Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the Participant from REMVEC II, CONVEX/ESCC, and the Maine Satellite as recorded in each Participant's FERC Form 1, Account No. 561, excluding any charges recorded in this account that were incurred under the NEPOOL Tariff or the Local Network Service Tariffs of each Transmission Provider as a Transmission Customer. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the Participant for providing scheduling and dispatch services, excluding any revenues recorded in this account that where received as a result of charges under the NEPOOL Tariff or the LNS Tariffs of each Transmission Provider.

REMVEC II is a satellite of the ISO-NE providing security analysis of PTF.

(*) Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each Participant's expenses as recorded in FERC Account No. 561, excluding any ISO and satellite related expenses and any expenses recorded in this Account, that were incurred under this Tariff or the LNS Tariffs of each Transmission Provider as a Transmission Customer, (*) multiplied by the PTF Transmission Plant Allocator, (2) SCADA-related expenses as calculated in accordance with Appendix A to this Rule, and (3) the Maine Satellite revenue requirements as calculated in accordance with Appendix A to this Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and non-PTF as determined for the applicable period pursuant to Attachment F of the NEPOOL Tariff.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers

WMECO Docket No. DTE 05-10
Record Request HD-01
Dated 09/13/2005
Q-RR-004
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SCHEDULE NU-1

Appendix B

DETERMINATION OF THE NU COMPANIES' NETWORK FORMULA REQUIREMENTS FOR TRANSMISSION SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

The NU Companies' formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

$$Formula\ Requirements_i = (A_{i-1} - B_{i-1})$$

WHERE:

- *i* equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of the NU Companies for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule NU-1.

  Next page

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of the NU Companies in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other applicable FERC Account for the calendar year prior to the Service Year.

  includes ISO regional S+D revenues

SCHEDULE NU-1

Appendix B

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the NU Companies is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES = The NU Companies' System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.

SCHEDULE NU-1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the NU Companies (if the NU Companies are the Control Area operator) or indirectly by the NU Companies making arrangements with the New England System Operator that performs this service for the NU Companies' Transmission System. The Transmission Customer must purchase this service from the NU Companies or the New England System Operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the New England System Operator performs this service for the NU Companies, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the NU Companies by that New England System Operator.

Each Point-To-Point Transmission Customer under this Local Service Schedule will be charged for Transmission Scheduling, System Control and Dispatch Services for the total Reserved Capacity specified in each reservation for Point-To-Point Transmission Service made under this Local Service Schedule at the rates set forth in Appendix A of this Schedule NU-1.

(*) Each Network Customer under this Local Service Schedule will be charged a monthly Transmission Scheduling, System Control and Dispatch Service Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Formula Requirements specified in Appendix B of this Schedule NU-1. - sheet 3231 - page 9

Each Transmission Customer with generation within the New England Control Area shall be required also to provide for Scheduling, System Control and Dispatch Service for that generation. It is anticipated that the Transmission Customer will obtain these services from the ISO. The NU Companies will make available Generation Scheduling, System Control and Dispatch Service at the rates set forth in Appendix C of this Schedule NU-1.

SCHEDULE 1

Appendix B

DETERMINATION OF

THE NU COMPANIES'

NETWORK FORMULA REQUIREMENTS

FOR TRANSMISSION SCHEDULING, SYSTEM CONTROL

AND DISPATCH SERVICE

The NU Companies' formula requirements for Network Transmission Scheduling, System Control and Dispatch Service is determined from the following formula.

$$Formula\ Requirements_i = (A_{i-1} - B_{i-1})$$

WHERE:

- i equals the calendar year during which service is being rendered ("Service Year").

- A_{i-1} is the Annual Control Center Expenses (expressed in dollars) of the NU Companies for the calendar year prior to the Service Year. The Annual Control Center Expenses are determined pursuant to the formula specified in Exhibit 1 to this Appendix B of Schedule 1.

see next page

- B_{i-1} is the actual transmission scheduling, system control and dispatch revenues (expressed in dollars) provided from the provision of transmission services to others. The actual transmission scheduling, system control and dispatch revenues shall be those recorded on the books of the NU Companies in FERC Account No. 456 pertaining to Transmission of Electricity for Others and such other

includes revenues associated with regional S+D

SCHEDULE 1

Appendix B

Exhibit 1

DETERMINATION OF ANNUAL CONTROL CENTER EXPENSES

The rate formula for determination of the annual control center expenses for each of the NU Companies is determined as follows:

A. ANNUAL CONTROL CENTER EXPENSES = The NU Companies' System Control and Load Dispatching Expense), for the calendar year prior to the Service Year as recorded in FERC Account 561.

Local Transmission Service includes S+D
Pre 10/27/03

ATTACHMENT H

Appendix A

DETERMINATION OF

THE NU SYSTEM COMPANIES'

NETWORK FORMULA REQUIREMENTS

FOR TRANSMISSION SERVICE

The NU System Companies' formula requirements for Network Transmission Service is determined from the following formula.

$$Formula\ Requirements_{\ i} = A - B + C_{i-1}$$

WHERE:

- *i* equals the calendar year during which service is being rendered ("Service Year").

- *A* is the Annual Revenue Requirements (expressed in dollars) of the transmission facilities of the NU System Companies, calculated in accordance with the Settlement Agreement filed and approved by the FERC in Docket Nos. ER95-1686-000 and ER96-496-000.

$13 rate allowed. Reported settlement revenue requirement level which includes S+D.

Local Transmission Service w/Study $ Pre 10/27/03 (cont'd)

! B is the transmission revenues (expressed in dollars) provided from the provision of transmission services to others, calculated in accordance with the Settlement Agreement filed and approved by the FERC in Docket Nos. ER95-1686-000 and ER96-496-000.

! C_{i-1} is the transmission payments to and revenues received (expressed in dollars) from NEPOOL in accordance with the NEPOOL Tariff. The actual NEPOOL transmission revenues received shall be those recorded on the books of the NU System Companies in FERC Account No. 456 pertaining to Regional Network Service and Through and Out Service, and such other applicable FERC Account for the calendar year prior to the Service Year. The actual NEPOOL payments shall include payments recorded in Account 565.

ISO Administrative Expenses Relating to S+D

Schedule 1
Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service ("Scheduling Service") is the service required to schedule at the regional level the movement of power through, out of, within, or into the ISO Control Area. For regional transmission service under the ISO Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must: be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO's charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the ISO Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this service pursuant to Schedule 1 of Section II of the ISO Tariff.

The ISO's expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the ISO Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with transmission services provided under the ISO Tariff;
- Transmission system planning which supports this Service; and
- Administrative costs associated with the aforementioned functions.

For the ISO's expenses in providing transmission-related Scheduling Service:

(A) each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.07485 per kilowatt times its Monthly Network Load for that month.

recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal the NU Companies' total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the NU Companies' Transmission reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and shall exclude all HQ HVDC expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-573. (*) Excludes Ac 561

Transmission Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the NU Companies' balance as assigned to transmission, as recorded in FERC Account 154.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the sum of the NU Companies' (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense (I) Transmission Support Expense, and(J) Transmission Related Taxes and Fees Charge.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the average balances of (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related

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Prepayments shall equal the NU Companies' prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the NU Companies' expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the NU Companies' deferred tax balance as recorded in FERC Account Nos. 281-283 and the NU Companies' deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the NU Companies' expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 408.1, 409.1.

Total Plant in Service shall equal the NU Companies' total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the NU Companies' Transmission reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal the NU Companies' expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 and shall exclude all HQ HVDC expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section I below, that are included in FERC Account Nos. 560-573.

⊕ Excludes account 561

Transmission Plant shall equal the NU Companies' gross plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the NU Companies' balance as assigned to transmission, as recorded in FERC Account 154.

II. Calculation of Transmission Revenue Requirements

The Transmission Revenue Requirement shall equal the

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573, and shall exclude all HQ HVDC expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Excludes account 561

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

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Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the Transmission Provider's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the Transmission Provider's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the Transmission Provider's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the Transmission Provider's transmission reserve balance as recorded in FERC Account 108.

(¥) Excludes A/c 561

Transmission Operation and Maintenance Expense shall equal the Transmission Provider's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573, and shall exclude all HQ HVDC expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the Transmission Provider's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the Transmission Provider's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the Transmission Provider's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities